

1 **DIRECT TESTIMONY**

2 **OF**

3 **KEVIN B. MARSH**

4 **ON BEHALF OF**

5 **SOUTH CAROLINA ELECTRIC & GAS COMPANY**

6 **DOCKET NO. 2015-103-E**

7
8 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND**
9 **POSITION.**

10 A. My name is Kevin Marsh and my business address is 220 Operation
11 Way, Cayce, South Carolina. I am the Chairman and Chief Executive
12 Officer of SCANA Corporation and South Carolina Electric & Gas
13 Company ("SCE&G" or the "Company").

14 **Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND**
15 **BUSINESS EXPERIENCE.**

16 A. I am a graduate, magna cum laude, of the University of Georgia,
17 with a Bachelor of Business Administration degree with a major in
18 accounting. Prior to joining SCE&G, I was employed by the public
19 accounting firm of Deloitte, Haskins & Sells, now known as Deloitte &
20 Touche, L.L.P. I joined SCE&G in 1984 and, since that time, have served
21 as Controller, Vice President of Corporate Planning, Vice President of
22 Finance, and Treasurer. From 1996 to 2006, I served as Senior Vice

1 President and Chief Financial Officer (“CFO”) of SCE&G and SCANA.
2 From 2001-2003, while serving as CFO of SCE&G and SCANA, I also
3 served as President and Chief Operating Officer of PSNC Energy in North
4 Carolina. In May 2006, I was named President and Chief Operating Officer
5 of SCE&G. In early 2011, I was elected President and Chief Operating
6 Officer of SCANA and I became Chairman and Chief Executive Officer of
7 SCANA on December 1, 2011.

8 **Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION BEFORE?**

9 A. Yes. I have testified in a number of different proceedings.

10 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS**
11 **PROCEEDING?**

12 A. In the Petition (the “Petition”), the Company requests that the Public
13 Service Commission of South Carolina (the “Commission”) approve an
14 updated construction schedule and schedule of forecasted capital costs for
15 the project to construct V.C. Summer Units 2 & 3 (the “Units”). My
16 testimony explains the requests contained in the Petition and the value the
17 Units represent to SCE&G’s customers, to its partner, Santee Cooper, and
18 to the State of South Carolina. I discuss the importance of this proceeding
19 to SCE&G’s plan for financing the Units and how this proceeding fits
20 within the structure of the Base Load Review Act (“BLRA.”)

21 **Q. WHAT OTHER WITNESSES ARE PRESENTING DIRECT**
22 **TESTIMONY ON BEHALF OF THE COMPANY?**

1 A. The other witnesses presenting direct testimony on behalf of the
2 Company are Mr. Stephen A. Byrne, Mr. Ronald A. Jones, Ms. Carlette L.
3 Walker and Dr. Joseph M. Lynch.

4 1. Mr. Byrne is the President for Generation and Transmission
5 and Chief Operating Officer of SCE&G. His testimony reviews the current
6 status of the construction of the Units and presents the updated construction
7 schedule provided by the contractors, Westinghouse Electric Company,
8 LLC (“WEC”) and Chicago Bridge & Iron (“CB&I”) (collectively
9 “WEC/CB&I”). Mr. Byrne also testifies concerning the commercial issues
10 with WEC/CB&I related to the project.

11 2. Mr. Jones is the Vice President for New Nuclear Operations
12 for SCE&G. Mr. Jones will testify concerning change orders related to the
13 project that SCE&G has agreed to with WEC/CB&I, changes in the
14 Estimated at Completion (“EAC”) costs and changes in Owner’s cost
15 arising from the new project schedule and other matters.

16 3. Ms. Walker is Vice President for Nuclear Finance
17 Administration at SCANA. She sponsors the current cost schedule for the
18 project and presents accounting, budgeting and forecasting information
19 supporting the reasonableness and prudence of the adjustments in cost
20 forecasts. Ms. Walker also testifies in further detail concerning key drivers
21 of the changes in the Owner’s cost forecast.

1 4. Dr. Lynch is Manager of Resource Planning at SCANA. He
2 will testify concerning updated studies showing that even considering
3 historically low natural gas prices, completing the Units remains the lowest
4 cost option for meeting the generation needs of SCE&G's customers.

5 All Company witnesses testify in support of the reasonableness and
6 prudence of the updated construction schedule and the costs it represents.
7 From my knowledge of the project and my perspective as SCE&G's Chief
8 Executive Officer, I can affirmatively testify that SCE&G is performing its
9 role as project owner in a manner that is reasonable, prudent, cost-effective
10 and responsible. The other witnesses are providing similar testimony about
11 the project from their particular areas of expertise.

12 **Q. PLEASE PROVIDE AN OVERVIEW OF THE REGULATORY**
13 **HISTORY OF THE PROJECT.**

14 A. In 2005, SCE&G began to evaluate alternatives to meet its
15 customers' need for additional base load capacity in the coming decades.
16 In this evaluation, the Company took account of its aging fleet of coal-fired
17 units, the volatility in global fossil-fuel markets, and the increasingly
18 stringent environmental regulations being imposed on fossil-fuel
19 generation. In its evaluation, the Company sought proposals from three
20 suppliers of nuclear generation units. The evaluation of all alternatives
21 resulted in the Company signing an Engineering, Procurement, and
22 Construction Agreement (the "EPC Contract") with what is now

1 WEC/CB&I on May 23, 2008, after two and one-half years of negotiations.
2 On May 30, 2008, the Company filed a Combined Application under the
3 BLRA seeking review by the Commission and ORS of the prudence of the
4 project and the reasonableness of the EPC Contract. The cost schedule
5 presented to the Commission in 2008 also included a reasonable forecast of
6 owner's contingency for the project. SCE&G's share of the total anticipated
7 cost was \$4.5 billion.¹ In December 2008, the Commission held nearly
8 three weeks of hearings and took evidence from 22 expert witnesses about
9 the project, the contractors, the EPC Contract and risks of construction.

10 **Q. WHAT WAS THE RESULT OF THOSE PROCEEDINGS?**

11 A. On March 2, 2009, the Commission issued Order No. 2009-104(A)
12 approving the prudence of the project and the schedules presented by the
13 Company. The South Carolina Supreme Court reviewed the Commission's
14 determinations and ruled that "based on the overwhelming amount of
15 evidence in the record, the Commission's determination that SCE&G
16 considered all forms of viable energy generation, and concluded that
17 nuclear energy was the least costly alternative source, is supported by
18 substantial evidence." *Friends of Earth v. Pub. Serv. Comm'n*, 387 S.C.
19 360, 369, 692 S.E.2d 910, 915 (2010). In a related case, *S.C. Energy Users*
20 *Comm. v. S.C. Pub. Serv. Comm'n*, 388 S.C. 486, 697 S.E.2d 587 (2010),

¹ Unless otherwise specified, all cost figures in this testimony are stated in 2007 dollars and reflect SCE&G's share of the cost of the Units.

1 the Court ruled that costs which were not identified and itemized to specific
2 expense items—specifically, owner’s contingency costs—could not be
3 included in the Commission-approved cost schedule for the Units. In
4 denying contingencies, the Court recognized that the BLRA allows the
5 Company to return to the Commission to seek approval of updates in cost
6 and construction schedules as the Company is doing here.

7 **Q. PLEASE DESCRIBE THE COST AND SCHEDULE UPDATES**
8 **SINCE ORDER NO. 2009-104(A) WAS ISSUED.**

9 A. Since 2009, SCE&G has appeared before the Commission three
10 times to update the cost and construction schedules for the Units.

11 1. In 2009, the Commission updated the construction schedule to
12 reflect a site-specific integrated construction schedule for the
13 project which WEC/CB&I had recently completed. The 2009
14 update changed the timing of cash flows for the project, but the
15 total forecasted cost for the Units of \$4.5 billion did not change.

16 2. A 2010 update removed un-itemized owner’s contingency from
17 the cost schedule in response to the decision in *S.C. Energy*
18 *Users Comm. v. S.C. Pub. Serv. Comm’n, supra*. The Company
19 also identified approximately \$174 million in costs that
20 previously would have been covered by the owner’s contingency.
21 The approved cost of the project dropped from \$4.5 to \$4.3
22 billion.

1 3. In 2012, the Commission updated the capital cost forecasts and
2 construction schedule. The cost forecasts were based on a
3 settlement between SCE&G and WEC/CB&I for cost increases
4 associated with:

- 5 a. The delay in the Combined Operating License (“COL”)
6 issued by the Nuclear Regulatory Commission (the
7 “NRC”);
- 8 b. WEC’s redesign of the AP1000 Shield Building;
- 9 c. The redesign by WEC/CB&I of certain structural modules
10 to be used in the Units; and
- 11 d. The discovery of unanticipated rock conditions in the Unit
12 2 Nuclear Island (“NI”) foundation area.

13 The Commission also updated the anticipated schedule of Owner’s
14 cost to reflect more detailed operations and maintenance planning; new
15 safety standards issued after the Fukushima event; and other matters. The
16 2012 update also involved several specific EPC Contract change orders. It
17 increased the anticipated cost for the Units from \$4.3 billion to \$4.5 billion.
18 The Commission adopted these new schedules in Order No. 2012-884.
19 South Carolina Supreme Court affirmed that order in *S.C. Energy Users*
20 *Comm. v. S.C. Elec. & Gas*, 410 S.C. 348, 764 S.E. 2d 913 (2014).

21 **Q. PLEASE PROVIDE AN OVERVIEW OF THIS PETITION.**

1 A. In this proceeding, SCE&G seeks approval of the revised milestone
2 schedule (the “Revised Milestone Schedule”) attached to Company Witness
3 Byrne’s direct testimony as Exhibit ____ (SAB-2). The updated schedule is
4 based on information recently provided to SCE&G by WEC/CB&I. It
5 shows new substantial completion dates for Units 2 and 3 of June 19, 2019,
6 and June 16, 2020, respectively (the “Substantial Completion Dates”).²

7 SCE&G has also submitted a revised cash flow forecast for the
8 project (the “Revised Cash Flow Forecast”). That schedule is attached to
9 Company Witness Walker’s direct testimony as Exhibit No. ____ (CLW-1).
10 It shows an updated cost forecast for the Units dollars of \$5.2 billion, which
11 is an increase of approximately \$698 million, or 15%, from the costs
12 approved in Order No. 2012-884.³ Chart A, below, summarizes these
13 adjustments.

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² SCE&G has not, however, accepted WEC/CB&I’s contention that the new Substantial Completion Dates are made necessary by excusable delays. Nothing in this testimony should be taken as a waiver or abandonment of any claims SCE&G may have against WEC/CB&I. Explanations of the reasons for certain delay or cost increases should not be taken as an indication that SCE&G agrees that the associated delays or cost increases are excusable under the EPC Contract or that WEC/CB&I is not liable to SCE&G for the resulting costs and other potential damages.

³ This \$698 million is net of approximately \$86 million in liquidated damages that SCE&G intends to seek from WEC/CB&I for the delays. While WEC/CB&I disputes this claim, SCE&G does not believe that WEC/CB&I’s counter position should be recognized in determining anticipated payments to complete the project.

1

2 **Q. HOW DOES THE CURRENT ANTICIPATED COST OF THE**
3 **PROJECT TO CUSTOMERS COMPARE TO THE ORIGINAL**
4 **PROJECTIONS?**

5 A. While the base capital cost of the project has increased, several
6 components of the ultimate cost of the project to customers are projected to
7 offset this increase:

8 a. **Capital cost.** Capital costs are increasing by \$712 million in 2007
9 dollars compared to the amount approved in Docket 2008-196-E. The
10 \$712 million increase reference here is different than \$698 million
11 increase referenced in the Petition but both are correct. The total cost
12 approved in Order No. 2012-884 was more than that approved in Order
13 No. 2009-104(A) by approximately \$14 million. As a result the increase
14 in anticipated costs is approximately \$698 million when compared to
15 Order No. 2012-884 and \$712 million when compared to Order No.
16 2009-104(A).

17 b. **Escalation.** The forecasted cost of escalation on the project has declined
18 by \$214 million compared to 2008. This is true even taking into account
19 the increased cost of the project, and the effect of extending the project
20 by two years.

1 c. **Financing.** Since 2008, SCE&G has been able to obtain low-cost
2 borrowing for the project based on support from the BLRA, SCE&G's
3 favorable bond ratings, and the low cost of financing available in debt
4 markets. Compared to the projections presented in 2008, customers are
5 anticipated to save approximately \$1.2 billion in interest costs (in future
6 dollars) over the life of the debt that has been issued to date to finance
7 the project and on future issuances where interest rates have been
8 hedged.

9 d. **Production Tax Credits.** The 2005 Energy Policy Act provides a
10 production tax credit to qualifying new nuclear units of 1.8 cents per
11 kWh during the first eight years of operation. The credits are limited to
12 6,000 MW of nuclear capacity built during a specified period with
13 qualifying units sharing the credits pro rata. In 2008, SCE&G
14 anticipated its total benefit would be \$1.06 billion gross of tax. Now it
15 appears that there will be a smaller number of competing utilities so that
16 SCE&G will receive a larger amount of credits. Assuming that the
17 current completion dates can be maintained, SCE&G's forecasted
18 benefit has increased by approximately \$1.2 billion in future dollars
19 since 2008. SCE&G intends to pass all of the savings from the tax
20 credits directly to its customers as fuel cost credits.

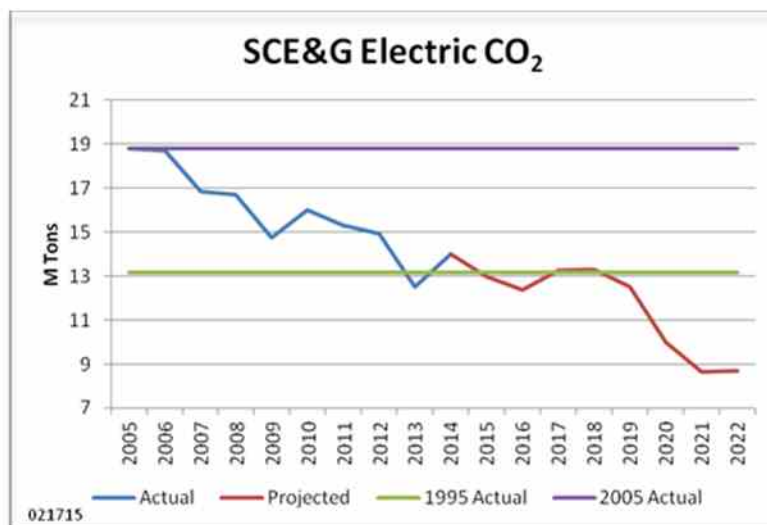
21 The impact of these savings will more than offset the impact to
22 customers of the forecasted \$712 million increase in 2007 capital cost. For

that reason, the combined capital and related cost to customers today does not exceed the estimate provided to the Commission in 2008.

Q. HOW HAS THE VALUE OF THE UNITS TO SCE&G'S SYSTEM CHANGED IN RECENT YEARS?

A. When SCE&G and Santee Cooper made the decision to construct these Units, they did so to capture the value of adding 2,234 MW of efficient and non-emitting, base-load generation to their generation portfolios to serve the people of South Carolina. In large part because of the Units, SCE&G projects that by 2021 it will have reduced its carbon emissions by 54% compared to their 2005 levels, and 34% compared to 1995 levels. Chart B shows the forecasted reduction in CO₂ emissions in millions of tons:

Chart B
SCE&G's Forecasted CO₂ Emissions



1 There have also been immediate environmental benefits from the
2 Units. In 2008, the Company committed to evaluate whether building the
3 Units might support retiring smaller coal units. The Company has followed
4 through on this commitment. Since 2008, SCE&G put in place plans to
5 retire 730 MW of smaller coal generating facilities. Canadys Units 1, 2 and
6 3 have been taken out of service. Urquhart Unit 3 has been converted to gas
7 generation only. For reliability purposes, SCE&G must maintain
8 McMeekin Units 1 and 2 in service pending the completion of the new
9 nuclear Units. But the current plan is to fuel the McMeekin units with
10 natural gas after April 15, 2016. They may be taken out of service
11 altogether when the Units come on line. SCE&G plans to bridge the gap
12 between these retirements and the completion of the new nuclear Units
13 through interim capacity purchases.

14 **Q. HOW DOES THE ENVIRONMENTAL PROTECTION AGENCY’S**
15 **(“EPA”) PROPOSED CLEAN POWER PLAN AFFECT THE**
16 **VALUE OF THE UNITS?**

17 A. EPA’s proposed Clean Power Plan was issued in June 2014. The
18 accompanying Clean Power Plan regulations are not yet in final form. But
19 they will require substantial cuts in CO₂ emissions from most state’s
20 electric generation fleets. Planning for these reductions underscores the
21 value and importance of nuclear generation.

22 **Q. HOW DOES THE CLEAN POWER PLAN WORK?**

1 A. The Clean Power Plan is based on Section 111(d) of the Clean Air
2 Act which governs existing generating units. In that plan, EPA has
3 computed a target carbon intensity rate for each state's fleet of existing
4 large power plants. That target carbon intensity rate is expressed in pounds
5 of carbon per megawatt hour of electricity generated (lb/MWh). The Plan
6 leaves it to the states to decide how to achieve mandated reductions and
7 how to allocate those reductions among plant operators.

8 In computing the target for South Carolina, EPA treats the Units as
9 existing units and assumes that they were operating at a 90% capacity
10 factor in 2012. The plan then mandates reductions in carbon intensity rate
11 from that artificially reduced baseline.

12 **Q. WHAT ARE THE SPECIFIC LIMITS BEING PROPOSED FOR**
13 **SOUTH CAROLINA?**

14 A. EPA is proposing that South Carolina reduce its discharges from its
15 actual 2012 carbon intensity of 1,587 lb/MWh to 772 lb/MWh, a 51%
16 reduction. Compliance will be phased-in beginning in 2020. In its
17 comments to EPA, SCE&G has proposed that the Units not be included in
18 the 2012 baseline calculation. If that is done, South Carolina's carbon
19 intensity target goes to 990 lb/MWh which would mean a reduction in
20 carbon emissions of 38% compared to actual 2012 emissions.

21 **Q. HOW DOES THIS AFFECT THE VALUE OF THE UNITS TO**
22 **SCE&G'S CUSTOMERS?**

1 A. It is not clear how the proposed EPA regulations will change, or how
2 the State will allocate the required reductions among affected power plant
3 owners. However, for South Carolina to meet its targets efficiently, it will
4 be critically important to complete the Units. There is no other source of
5 non-emitting, dispatchable, base load power available to replace the
6 generation represented by the Units. Generation sources that produce any
7 air emissions are now under intense regulatory pressure. There is no reason
8 to assume that this trend will not continue over the long term. Adding non-
9 emitting nuclear generation has tremendous value in the current
10 environmental context.

11 **Q. WHAT ABOUT OTHER NON-EMITTING TECHNOLOGIES?**

12 A. Solar and renewable resources and energy efficiency will play an
13 increasingly important role in SCE&G's generation mix going forward.
14 SCE&G was an active participant in the group that formulated and
15 advocated the adoption of the South Carolina Distributed Energy Resources
16 Act found in Act No. 236 of 2014. SCE&G is currently working to achieve
17 the renewable resources goals established by the South Carolina General
18 Assembly in that Act. The achievement of those goals is fully reflected in
19 all of our capacity and generation forecasts. The same is true of the energy
20 efficiency goals established in SCE&G Demand Side Management (DSM)
21 program as approved by this Commission. However, with current

1 technologies, renewable resources and energy efficiency cannot displace
2 the need for reliable, dispatchable base load generation.

3 Because of EPA regulations limiting carbon discharges, it is
4 extremely difficult to permit new coal generation. For that reason, the only
5 dispatchable, base load alternative to nuclear generation today is combined-
6 cycle natural gas generation. Natural gas generation involves lower levels
7 of CO₂, NO_x, and SO_x emissions than coal. However, natural gas
8 generation does entail some emissions of CO₂ and the six criteria air
9 pollutants. Nuclear generation remains the only base load resource that is
10 entirely non-emitting with respect to these air pollutants.

11 **Q. WHAT IS SCE&G'S PLAN TO REDUCE ITS CO₂ EMISSIONS?**

12 A. As the Company's witnesses testified in 2008, one of SCE&G's
13 long-term goals in choosing to use new nuclear generation was to create a
14 system with a majority of its energy being supplied from non-emitting
15 sources. Chart C on the following shows how that plan stands today.

16 [Chart C begins on the following page]

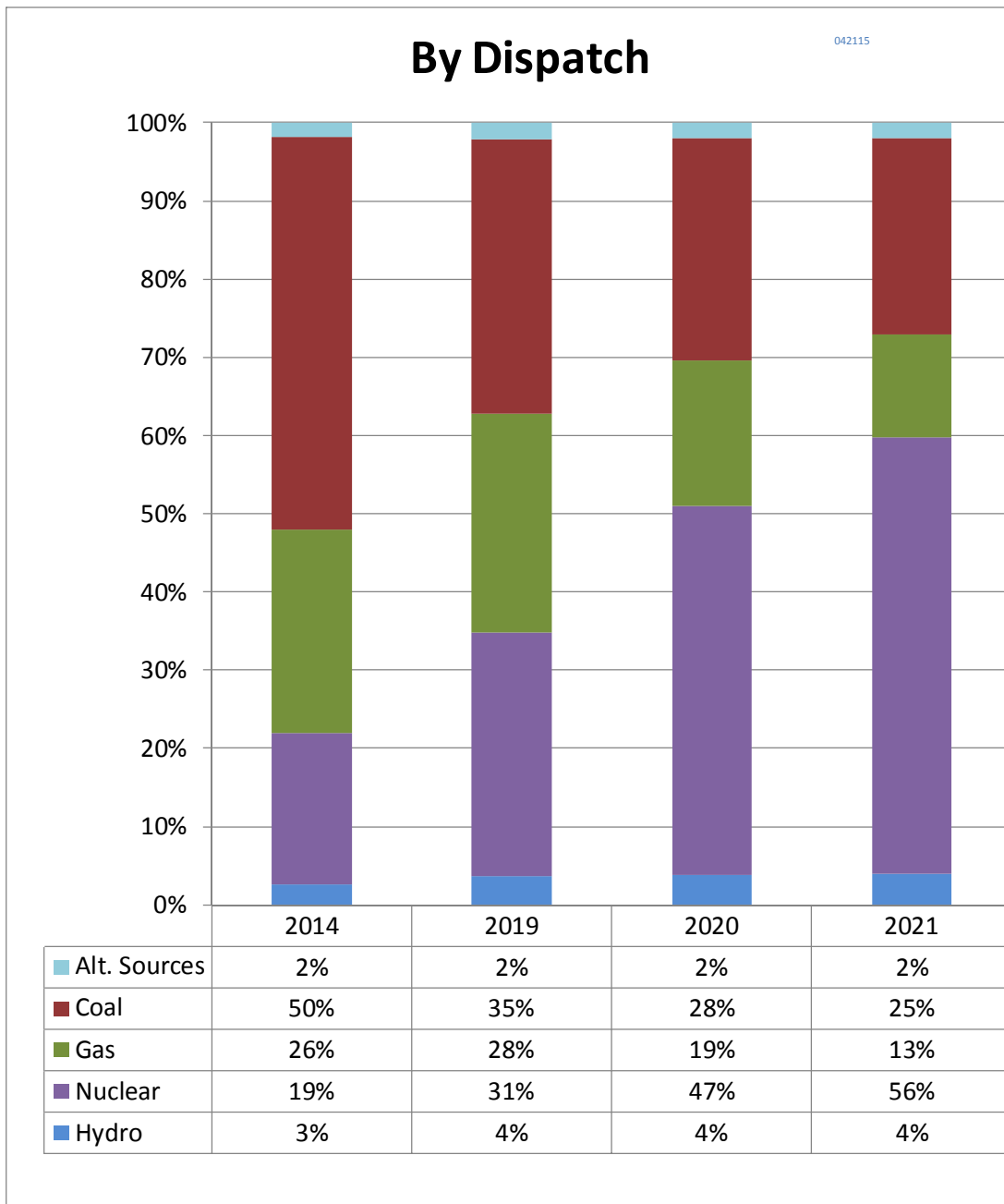
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Chart C
SCE&G's Current and Forecasted Generation Mix



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In 2014, 23% of SCE&G generation of energy was from non-emitting facilities. (Approximately one-half of the Alternative Resources

1 listed in Chart C are non-emitting. The remainder is biomass). In 2021,
2 which is the first full year that both Units 2 and 3 will be on line, we
3 estimate that 61% of the energy serving SCE&G's customers will come
4 from non-emitting sources. SCE&G is on track to achieve its goal to create
5 a generating system with markedly reduced levels of CO₂ emissions and
6 reduced exposure to the risk and costs associated with them.

7 **Q. IN 2008, DIVERSIFICATION OF FUEL SOURCES WAS AN**
8 **IMPORTANT GOAL FOR SCE&G. IS THAT TRUE TODAY?**

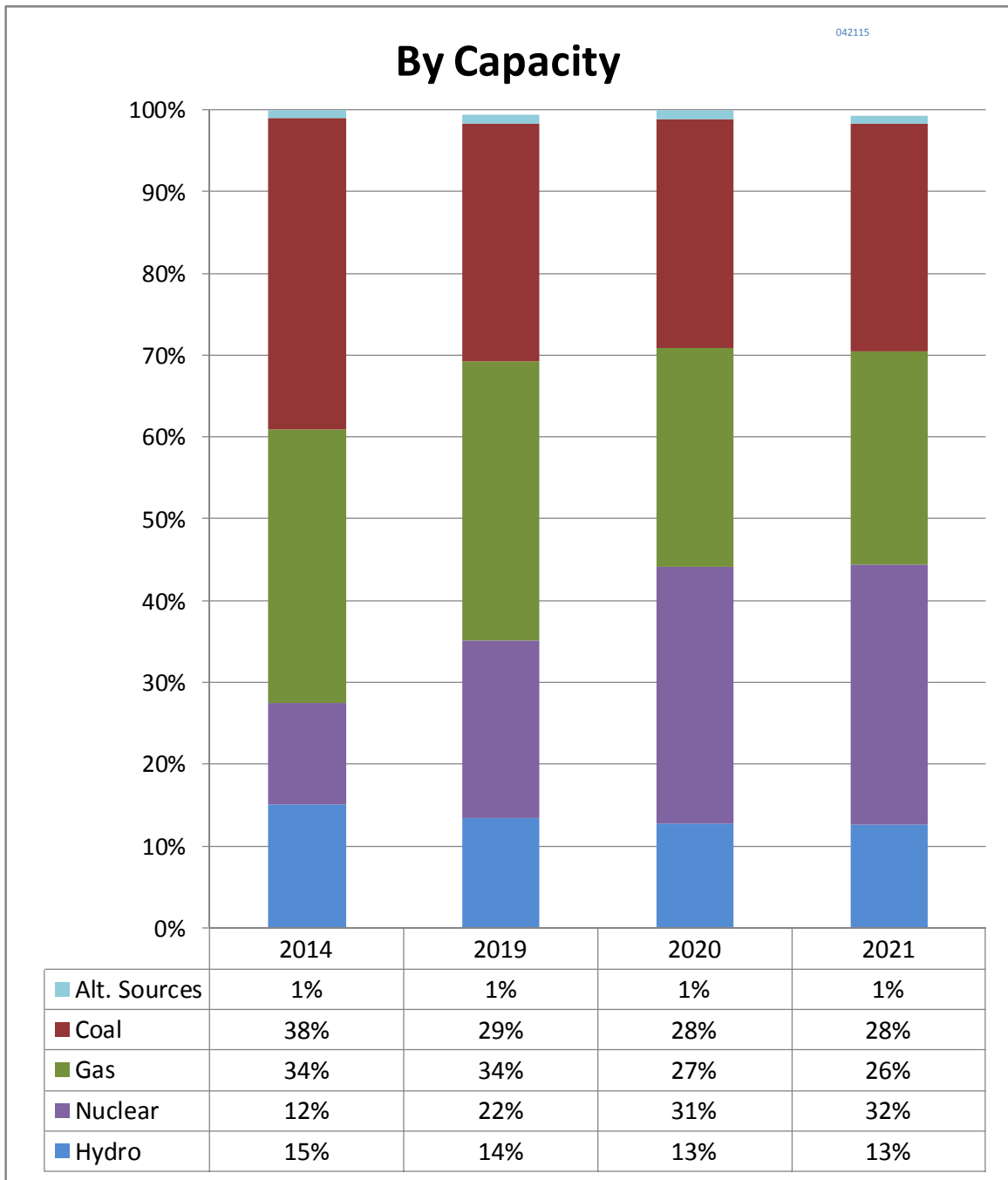
9 A. The Company testified in 2008 that diversification of fuel sources
10 was an important reason why adding nuclear generation would provide
11 value to SCE&G's customers. That continues to be the case today.

12 SCE&G's current capacity mix is weighted 72% towards fossil fuel,
13 with coal representing 38% of that capacity, and natural gas representing
14 34%. In large part because of the addition of nuclear generation, SCE&G
15 will have a well-balanced generation system in 2021 with 28% of its
16 capacity in coal units, 26% of its capacity in natural gas units, 32% of its
17 capacity nuclear units and 14% of its capacity in hydro/biomass/solar
18 facilities. In 2021, the three principal fuel sources, nuclear, coal and natural
19 gas, will each represent a significant and balanced component of capacity.
20 Chart D shows this capacity mix in a graphic form:

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Chart D
SCE&G's Current and Forecasted Capacity Mix



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Creating this balanced mix of capacity will give SCE&G operating

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flexibility to respond to changing market conditions and environmental

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regulations. I am not aware of a cost effective way today to create this

1 flexibility other than by adding new nuclear capacity. This is particularly
2 true now that for environmental reasons adding new coal capacity is no
3 longer feasible. If SCE&G were to meet its 2020-2021 base load generation
4 needs by adding new natural gas generation, then fossil fuels (natural gas,
5 oil, and coal) would account for approximately 75% of SCE&G's
6 generation in 2021, with gas alone representing 48% of its generation.
7 Given the increasing environmental pressures on coal and the technological
8 limitations on relying on renewables for base load capacity, under any
9 reasonable scenario the system's reliance on natural gas is likely to go up
10 steadily in the years following 2021. Without the new nuclear capacity
11 represented by the Units, SCE&G's system would likely be locked into a
12 significantly unbalanced generation portfolio with increasing reliance on
13 natural gas generation today and in the decades to come.

14 On the other hand, adding nuclear capacity creates a balanced
15 generation portfolio. As was the case in 2008, this continues to be an
16 important reason that building these Units provides value to our customers.

17 **Q. DO CURRENT LOW NATURAL GAS PRICES CHANGE THE**
18 **VALUE THAT THE UNITS WILL PROVIDE TO CUSTOMERS?**

19 A. Hydraulic fracturing, or "fracking," has reduced the cost and
20 increased the supply of natural gas at this time and for some years in the
21 future. However, predictions of future natural gas prices are notoriously
22 unreliable over the long-term. The planning horizon for determining the

1 value of a nuclear unit is 60 years or more. Prices for fuels are historically
2 volatile as natural gas will change over that time. The lesson of history is
3 that fossil fuel prices will change dramatically and unexpectedly over that
4 long a time. Therefore, prudent utility generation plans seek to create
5 balanced systems that can respond as prices fluctuate over time and are not
6 overly dependent on any one fuel source. As discussed above, that is what
7 SCE&G's generation plan seeks to do.

8 In the case of natural gas supplies and fracking, there are efforts
9 underway to limit fracking based on environmental concerns. But the issues
10 go beyond fracking. The Sierra Club indicates on its current website that it
11 is committed to "putting natural gas back in the dirty box with its fossil fuel
12 brethren." In its "Beyond Natural Gas" campaign, the Sierra Club tells
13 readers of its website that "[t]otal life-cycle emissions for coal and gas are
14 nearly equivalent," and that "[t]he Sierra Club continues to legally
15 challenge new natural gas plants and demand requirements that limit their
16 emissions of greenhouse gases." According to the Sierra Club, "[n]atural
17 gas is not part of a clean energy future."⁴ It is only reasonable to assume
18 that once coal plants are closed, restricting natural gas generation will
19 become the principal focus of entities like the Sierra Club.

20 In addition, domestic United States natural gas prices are still out of
21 line with global prices:

⁴ <http://content.sierraclub.org/naturalgas/protect-our-climate> (accessed May 20, 2015).

CHART E

Landed LNG Prices, April 2015

(\$US/MBTU)

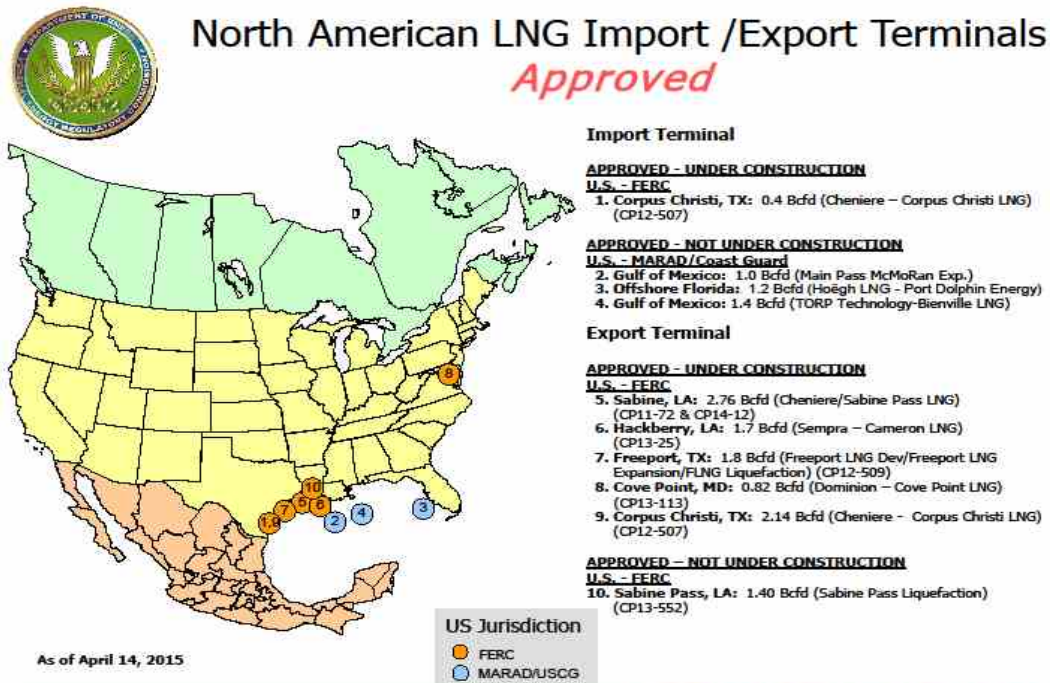


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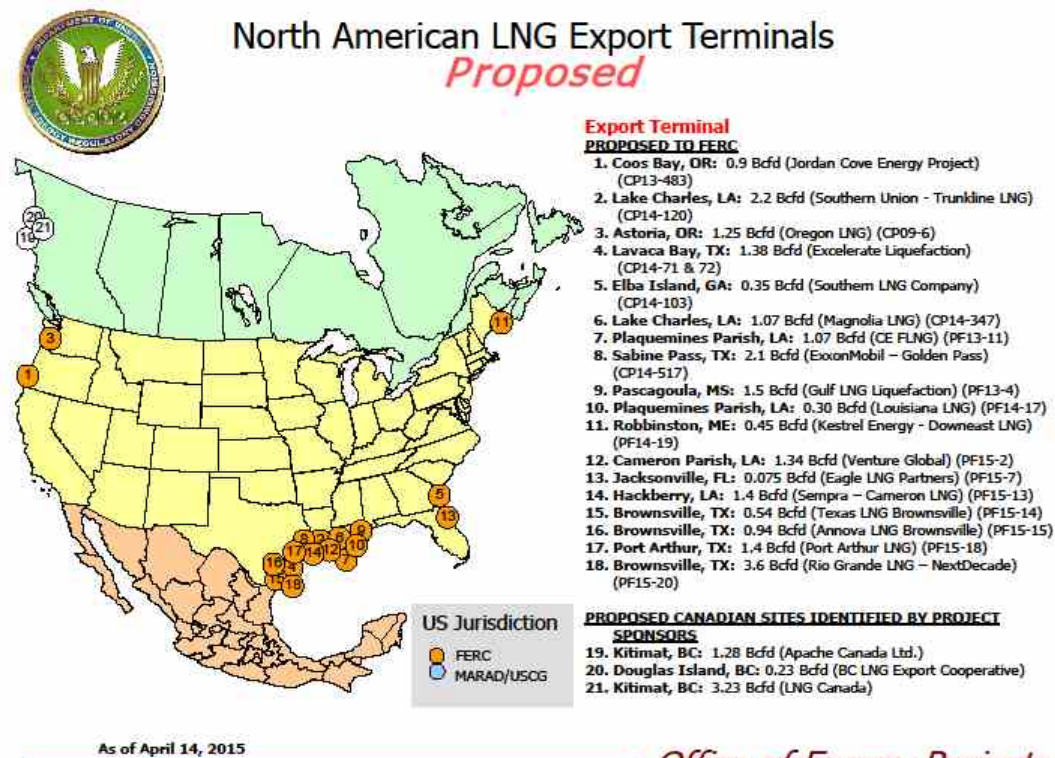
Updated: April 2015

How long the current price disparities can remain is difficult to determine. But there is every reason to expect that in the coming years U.S. natural gas prices may begin to respond to global markets and the global hunger for energy. Major energy companies are moving to expand their infrastructure to export natural gas produced in the United States as liquefied natural gas (“LNG”). A review of the reported 2015 data indicate that 24 new LNG export facilities have been approved or proposed to be permitted in the United States. Another 26 sites are listed as potential export sites in North America.

CHART F



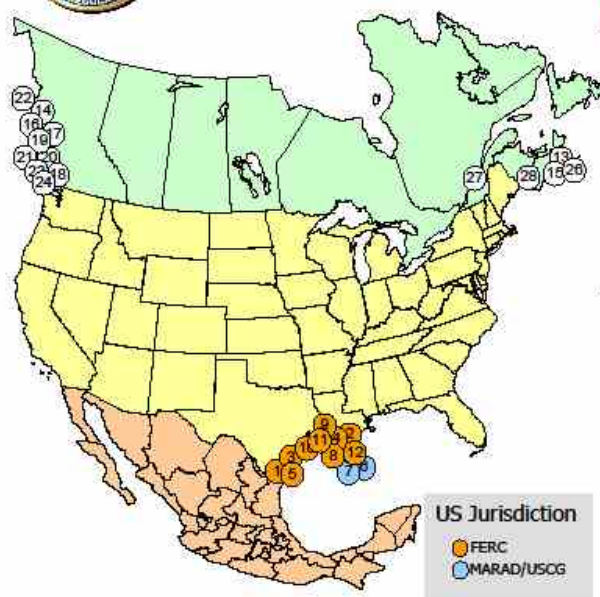
Office of Energy Projects



Office of Energy Projects



North American LNG Export Terminals *Potential*



Export Terminal

POTENTIAL U.S. SITES IDENTIFIED BY PROJECT SPONSORS

1. Brownsville, TX: 2.8 Bcfd (Gulf Coast LNG Export)
2. Cameron Parish, LA: 0.16 Bcfd (Waller LNG Services)
3. Ingleside, TX: 1.09 Bcfd (Pangea LNG (North America))
4. Cameron Parish, LA: 0.20 Bcfd (Gasfin Development)
5. Brownsville, TX: 3.2 Bcfd (Eos LNG & Barca LNG)
6. Gulf of Mexico: 3.22 Bcfd (Main Pass - Freeport-McMoRan)
7. Gulf of Mexico: 1.8 Bcfd (Delfin LNG)
8. Cameron Parish, LA: 1.60 Bcfd (SCT&E LNG)
9. Port Arthur, TX: 0.2 Bcfd (WesPac/Gulfgate Terminal)
10. Galveston, TX: 0.77 Bcfd (NextDecade)
11. Calcasieu Parish, LA: 0.64 Bcfd (Live Oak LNG-Parallax Energy)
12. Cameron Parish, LA: 1.84 Bcfd (G2 LNG)

POTENTIAL CANADIAN SITES IDENTIFIED BY PROJECT SPONSORS

13. Goldboro, NS: 1.4 Bcfd (Pieridae Energy Canada)
14. Prince Rupert Island, BC: 2.91 Bcfd (BG Group)
15. Melford, NS: 1.8 Bcfd (H-Energy)
16. Prince Rupert Island, BC: 2.74 Bcfd (Pacific Northwest LNG)
17. Prince Rupert Island, BC: 4.0 Bcfd (ExxonMobil - Imperial)
18. Squamish, BC: 0.29 Bcfd (Woodfibre LNG Export)
19. Kitimat/Prince Rupert, BC: 0.32 Bcfd (Triton LNG)
20. Prince Rupert, BC: 3.12 Bcfd (Aurora LNG)
21. Kitsault, BC: 2.7 Bcfd (Kitsault Energy)
22. Stewart, BC: 4.1 Bcfd (Canada Stewart Energy Group)
23. Delta, BC: 0.4 Bcfd (WesPac Midstream Vancouver)
24. Vancouver Island, BC: 0.11 Bcfd (Steelhead LNG)
25. Prince Rupert Island, BC: 3.2 Bcfd (Orca LNG)
26. Port Hawkesbury, NS: 0.5 Bcfd (Bear Head LNG)
27. Saguenay, Quebec: 1.6 Bcfd (GNL Quebec)
28. Saint John, NB: 0.67 Bcfd (Saint John LNG Development)

As of April 14, 2015

Office of Energy Projects

Furthermore, there are questions about how to make sufficient pipeline capacity available to transport natural gas to consumers if the greater part of the nation's future energy needs will be supplied by natural gas indefinitely. A number of new pipelines are under construction or have been proposed such as the new Atlantic Coast Pipeline being constructed from West Virginia to North Carolina. Capacity in these pipelines will be significantly more expensive than existing pipeline capacity.

SCE&G continues to believe that over the long planning horizon that is involved when procuring base load generation units, the unbalanced reliance on any single fuel source is dangerous from both a cost and a reliability standpoint. Over the long-term, prices will change unpredictably.

1 I have testified to that fact before this Commission in past proceedings. It
2 continues to be my firm belief.

3 **Q. WHERE DOES COMPANY'S FINANCIAL PLAN REGARDING**
4 **THE UNITS PLAN STANDS TODAY?**

5 A. As of March 2015, SCE&G had successfully raised the capital
6 necessary to support \$3.1 billion of the \$6.8 billion cost of the Units in
7 future dollars (which is comparable to \$5.2 billion in 2007 dollars). This
8 represents approximately 46% of the value of the Units when completed.
9 SCE&G has supported this investment through issuance of debt in the form
10 of first mortgage bonds of SCE&G and equity from SCE&G's retained
11 earnings, and sales of common stock by SCANA and retained earnings of
12 SCANA, the proceeds of which have been contributed to SCE&G. Where
13 possible, SCE&G has locked in favorable interest rates for future
14 borrowings. As of March 2015, interest rates on approximately \$1.3 billion
15 in anticipated 2015-2016 borrowings have been locked in at an estimated
16 effective rate of 5.09%.

17 **Q. HOW HAS THE FINANCIAL COMMUNITY RESPONDED TO**
18 **SCE&G'S BORROWING TO SUPPORT THE UNITS?**

19 A. As evidenced by SCE&G's recent debt offerings, the financial
20 community has been supportive of SCE&G's plan to finance the
21 construction of these Units. The financial community is comfortable with
22 the careful and consistent approach to applying the BLRA that has been

1 followed by the ORS and Commission since its adoption. Since 2009,
2 SCE&G has issued approximately \$1.5 billion in first mortgage bonds
3 through eight separate issues that are directly related to the nuclear project.
4 The weighted average interest rate of these bonds is only 4.99%.

5 **Q. COULD YOU PROVIDE EXAMPLES OF SUCCESSFUL**
6 **MARKETING OF BONDS IN RECENT YEARS?**

7 A. SCE&G's \$250 million bond issue in February 2011 was
8 oversubscribed by a factor of eight and was ultimately priced at the lowest
9 end of the indicated interest rate range. SCE&G's \$250 million bond issue
10 in January 2012 was oversubscribed by a factor of six and, when issued,
11 bore "one of the lowest 30-year coupons of all time," as reported at the time
12 by Credit Suisse. Nevertheless, the next issue, which was SCE&G's \$250
13 million issue in July 2012, bore a yield which "represent[ed] the lowest 30-
14 year utility yield on record," as reported at that time by Well Fargo.
15 SCE&G's \$300 million May 2014 bond issue represented the first 50-year
16 bond issued in the utility and power sector and only the sixth such bond
17 ever issued in the United States. It was oversubscribed by a factor of 13 and
18 was issued at a rate estimated to be only 35 basis points higher than a 30-
19 year bond would have borne.

20 **Q. HOW DID THE MARKET RESPOND TO SCE&G'S MOST**
21 **RECENT BOND ISSUE?**

1 A. In May of this year, SCE&G issued \$500 million in 50-year first
2 mortgage bonds. The interest rate was favorable at 5.1%. However, on the
3 day of the issuance the subscriptions for this issue were slow in coming. At
4 one point, it appeared that the entire \$500 million might not be sold. In the
5 closing hours of the offering, it required a slight nudge upward in the
6 interest rate to bring the book of potential buyers from \$400 million to the
7 expected \$500 million. While the interest rate on the bonds was still very
8 good, it was the first time in recent years that the issuance was not
9 oversubscribed. In most other cases, the bonds were quickly
10 oversubscribed.

11 **Q. DO YOU KNOW WHY THESE BONDS WERE MORE DIFFICULT**
12 **TO SELL?**

13 A. We polled several investment banking firms involved in the
14 transaction. They reported that an important factor for many potential
15 buyers was their concern over regulatory risk related to the current filing.
16 Bond buyers have options. If bond buyers have concerns about SCE&G's
17 risk profile, it is often just as easy for them to buy bonds of companies that
18 do not face such risks as to buy SCE&G's bonds.

19 **Q. WHAT IS YOUR CONCLUSION FROM THESE FACTS?**

20 A. The market is becoming increasingly sensitive to SCE&G's
21 regulatory risk in the nuclear context. The 'overhang' of the current
22 proceeding has brought that risk into focus for the market. We were able to

1 complete the transaction successfully and at a good interest rate, but what
2 we learned is that the risk of losing market support for our financing plan is
3 real. That could happen if the market loses confidence in the consistent
4 application of the BLRA.

5 **Q. WHAT IS THE FINANCIAL PLAN FOR COMPLETING THE**
6 **UNITS GOING FORWARD?**

7 A. In mid-2015, we are entering a critical time in the execution of our
8 financial plan. We anticipate spending approximately \$940 million on the
9 Units in 2015, approximately \$1 billion in 2016, and approximately \$900
10 million in 2017. After that time, annual capital expenditures are anticipated
11 to drop quickly. During this three year period, SCE&G will not have the
12 option of waiting out unfavorable conditions in the capital markets or
13 postponing issues during periods where it has achieved unfavorable
14 financial or regulatory results as a company. During this time, it will be
15 vitally important that SCE&G maintain access to capital markets on
16 favorable terms. If SCE&G can maintain access on such terms, the
17 Company may be able to continue to reduce debt costs and the costs to
18 customers from financing the Units as compared to the 2008 projections.
19 However, if access to capital markets on favorable terms is lost, the reverse
20 is true. Financing costs will go up, and in some circumstances, it could
21 prove impossible to finance the completion of the Units.

1 **Q. WHAT ROLE DOES THIS PROCEEDING PLAY IN SCE&G**
2 **EXECUTING ITS FINANCIAL PLAN?**

3 A. Nothing is more important to SCE&G's financial plan than that we
4 sustain the market's understanding that ORS and the Commission will
5 continue to apply the BLRA in a fair and consistent way. The financial
6 markets understand that the Commission and ORS may come under
7 pressure to deviate from the terms of BLRA as challenges appear in the
8 construction project. The decision here will provide the financial markets
9 with an important signal concerning how the markets should expect that the
10 BLRA will be applied over the remaining five years of the project. That
11 will greatly impact how the financial community assesses the financial and
12 regulatory risks of the project and the rates and terms on which SCE&G
13 will be able to finance the approximately \$3.4 billion of debt and equity
14 that remains to be raised.

15 **Q. PLEASE EXPLAIN WHY YOU BELIEVE THAT THE BLRA IS SO**
16 **IMPORTANT TO THE FINANCING PLAN FOR THE UNITS.**

17 A. The BLRA was adopted to make it possible for electric utilities like
18 SCE&G to consider building new nuclear units. Before the BLRA was
19 adopted, building a new nuclear plant was not a viable option for SCE&G.
20 For SCE&G to seriously consider adding new nuclear capacity, legislative
21 action was needed to overcome two major challenges. These are the two
22 challenges which the BLRA sought to address:

1 **The Financing Challenge.** Recovering the financing costs of a
2 project during construction was the first challenge. During construction of a
3 base load plant, a company must raise hundreds of millions of dollars of
4 new capital each year to finance construction costs. Each time bonds are
5 issued to pay for construction, debt service increases. Unless there is a
6 corresponding increase in revenues, debt service coverage ratios decline as
7 do other financial ratios. Bond ratings are based on these ratios. As these
8 ratios decline, the creditworthiness of the company suffers. In time, bond
9 ratings are downgraded. At that point, raising capital on favorable terms
10 can be extremely difficult or potentially impossible. Capital to complete
11 the plant may not be available.

12 On the equity side, each time additional common stock is issued to
13 support construction, there are more shares outstanding. Additional
14 dividends must be paid. Without new revenues, earnings are diluted. As
15 earnings are diluted, the attractiveness of the stock and its value decline. To
16 finance the next round of construction, a higher number of lower-priced
17 shares must be issued to generate the same amount of capital. This causes
18 yet more dilution and further weakens the value of the stock going into the
19 next financing cycle.

20 The only solution is for the company to generate revenues sufficient
21 to pay debt service, meet coverage ratios and provide reasonable levels of
22 earnings per share as the new plant is built. Some years ago the

1 Commission recognized this fact and began to authorize utilities to include
2 the financing costs of plants in rates before they were completed. This was
3 done in general rate cases by recognizing the financing costs associated
4 with construction work in progress (“CWIP”) as an expense for ratemaking
5 purposes. The Commission has historically allowed a company to apply its
6 weighted average cost of capital to its CWIP to determine the amount of
7 revenue needed to support the common stock and bonds issued to finance
8 construction. The weighted average cost of capital is the amount of
9 revenue that the Commission has determined to be necessary to support
10 investment of capital in the utility, specifically, to pay debt service on
11 bonds and allow a reasonable level of earning to support common stock.

12 But this CWIP based approach required the utility to file general rate
13 cases during plant construction. This produced rate adjustments that were
14 stair stepped in one or two-year intervals. SCE&G successfully used this
15 approach when building its last coal plant, Cope Station (1995), and its
16 most recent combined cycle natural gas plant, Jasper Station (2004). During
17 construction, there were a total of six separate rate adjustments which
18 placed some part of the financial costs of the capital spent on those plants
19 into rates.

20 Cope and Jasper, however, took three to five years to build, not
21 twelve as is the case for nuclear. Outlays for those plants were in the
22 hundreds of millions of dollars, not billions. If this approach were to be

1 used to support a nuclear construction project, it would require SCE&G to
2 litigate full electric rate cases every year or two for approximately 12 years.
3 Neither SCE&G nor its investors considered this to be practical.

4 **Disallowances.** The second challenge utilities like SCE&G faced in
5 base load construction was the threat of construction cost disallowances.
6 Investors are sensitive to very small changes in returns. Even ‘minor’
7 construction cost disallowances can hit investor returns with crippling
8 force. For example, it takes only a five percent disallowance of principal in
9 a given year—\$50 million on a \$1 billion investment—to cut a ten percent
10 return in half. Even a small disallowance today indicates the potential for
11 future disallowances as construction progresses. Therefore, even small
12 disallowances can drive investors away and make it impossible for a utility
13 to complete a construction project due to lack of financing.

14 These financial realities are facts that opponents of nuclear power
15 used to great effect in the last nuclear construction cycle. They underscore
16 why SCE&G believes that even a small departure from the terms of the
17 BLRA could cause the investment community to fundamentally change its
18 assessment of SCE&G’s future regulatory risk.

19 **The BLRA.** In response, the South Carolina General Assembly
20 adopted the BLRA. It allows for annual rate adjustments through revised
21 rates filings to cover the financing costs of approved nuclear construction
22 projects pending their completion. Financing costs are based on the same

1 weighted average cost of capital that applies under the CWIP method. As
2 with the CWIP method, before a plant goes into service, only financing
3 costs may be recovered under the BLRA, not the cost of the plant itself.
4 The BLRA carries forward the key concepts of the CWIP method but does
5 so without requiring full rate cases each year which would not be practical.

6 As to disallowances, the BLRA provides an opportunity for the
7 Commission to review the prudence of constructing the plant in detail
8 before construction begins. Once the prudence decision is made,
9 disallowances are permitted if (a) the construction does not proceed within
10 the originally approved cost and construction schedules and (b) schedule
11 amendments such as the updates that are requested here are not made. As
12 to the second point, the BLRA states that the Commission will grant
13 requests for amendment as long as “the evidence of record justifies a
14 finding that the changes are not the result of imprudence on the part of the
15 utility.” S.C. Code Ann. § 58-33-270(E)(1).

16 Under the BLRA, prudence reviews are made based on plans and
17 forecasts before construction begins. The Commission determines whether
18 or not it is prudent to proceed with the project under the construction plan
19 and with the contractors and EPC contract proposed by the Company. The
20 initial plans and forecasts can then be updated so long as the updates are not
21 the result of imprudence by the utility. This assures the financial
22 community that disallowances based on after-the-fact prudence challenges

1 will not impair their ability to recover the capital they invest in the project
2 unless there is imprudence by the utility in administering the project.

3 **Q. WHAT DO YOU BELIEVE TO BE THE POLICY BEHIND**
4 **LIMITING THE PRUDENCY REVIEW IN UPDATE DOCKETS TO**
5 **THE PRUDENCY OF THE OWNER IN MANAGING THE**
6 **PROJECT?**

7 A. In considering disallowances, the BLRA properly focuses on the
8 utility as owner of the project and those cases where the utility has caused
9 additional cost to be incurred through imprudence in its role as owner.
10 More specifically, in this project, the Commission properly looks to
11 SCE&G as owner for prudence in

- 12 • construction oversight;
- 13 • obtaining licenses and permits for the Units including NRC
- 14 licenses, and complying with those licenses and permits;
- 15 • administering the EPC Contract and enforcing its terms;
- 16 • resolving disputes with the EPC contractors;
- 17 • constructing transmission facilities to support the Units;
- 18 • recruiting, hiring and training of operating staff for the Units;
- 19 • deploying information technology (“IT”) systems to support the
- 20 Units;

- drafting and obtaining approval of the operating, maintenance and safety plans for the Units; and
- performing all the tasks that fall under the heading of operational readiness for the Units.

The BLRA provisions as to cost and construction schedule updates properly focus on those aspects of the project that the Company can control, specifically its own prudence as owner in administering the EPC contract, overseeing the contractor's work and performing the work that is the owner's direct responsibility. Other risks related to construction are reviewed in the initial BLRA proceeding when the EPC contract, EPC contractor, and other aspects of the project are being approved. The decision to approve a project under the BLRA is a decision that it is reasonable and prudent to assume the risks of proceeding given the terms of the EPC contract, the review of the EPC contractor, and the other matters considered.

Q. IS THIS POSITION CONSISTENT WITH THE COMMISSION'S PRIOR RULINGS UNDER THE BLRA?

A. In the 2008 proceedings, the Commission and the parties reviewed the risk factors associated with this project and concluded that the project should proceed under the terms of the BLRA in spite of those risks. Based on its review of that information, the Commission ruled as follows:

1 The Commission's approval of the reasonableness and
2 prudence of the Company's decision to proceed with construction of
3 the Units rests on a thorough record and detailed investigation of the
4 information known to the Company and the parties at this time.
5 Once an order is issued, the Base Load Review Act provides that the
6 Company may adjust the approved construction schedule and
7 schedules of capital cost if circumstances require, so long as the
8 adjustments are not necessitated by the imprudence of the Company.
9 S.C. Code Ann. § 58-27-270(E). The statute does not allow the
10 Commission to shift risks back to the Company. ... In addition, risk
11 shifting could jeopardize investors' willingness to provide capital for
12 the project on reasonable terms which, in turn, could result in higher
13 costs to customers.

14
15 Order No. 2009-104(A), p. 92. On appeal, the South Carolina Supreme
16 Court described that order as “a very thorough and reasoned order.”
17 *Friends of Earth v. Pub. Serv. Comm'n of S. Carolina*, 387 S.C. 360, 372,
18 692 S.E.2d 910, 916 (2010). The court stated that “the Commission
19 addressed each and every concern Appellant presented” *Id.*

20 **Q. WHAT INFORMATION ABOUT RISKS DID SCE&G PLACE**
21 **BEFORE THE COMMISSION IN 2008?**

22 A. When SCE&G filed for BLRA approval in 2008, it placed before the
23 Commission an extensive assessment of the risks and uncertainties of this
24 project. SCE&G also placed before the Commission its choice of EPC
25 contractors, its plan for construction of the Units, and the terms of the EPC
26 Contract under which subcontractors would be selected and the Units
27 would be constructed. SCE&G explained:

28 SCE&G has reviewed the risks related to constructing the Units
29 carefully and over an extended period of time. It has compared those
30 risks to the risks of the other alternatives that are available to meet

1 the energy needs of its customers and the State of South Carolina. . .
2 . SCE&G has concluded that constructing the Units is the most
3 prudent and responsible course it can take at this time to meet the
4 base-load generation needs of its Customers. . . .

5
6 ...In the end, this project's ability to meet its current schedule and
7 cost projections will depend on the cumulative effect of those risk
8 events that do occur on the schedule and cost projections contained
9 in this Application.

10
11 Petition, Docket No. 2008-196-E, Exhibit J, p. 12.

12 SCE&G's 2008 BLRA application acknowledged that, "[f]or a
13 project of the scope and complexity of the licensing and constructing of the
14 Units, any list of potential risk factors compiled at this stage of the process
15 will not be exhaustive." Petition, Docket No. 2008-196-E, Exhibit J, p. 12.
16 With that caveat, SCE&G listed the specific risks that seemed most
17 important at the time. Among the risks specifically enumerated at that time
18 were many, if not all, of the risks that have resulted in the current update
19 filing:

- 20 • Module production: "It is possible that manufacturers of unique
21 components (e.g., steam generators and pump assemblies or other
22 large components or modules used in the Units) and
23 manufacturers of other sensitive components may encounter
24 problems with their manufacturing processes or in meeting
25 quality control standards. . . . Any difficulties that these foundries
26 or other facilities encounter in meeting fabrication schedules or

1 quality standards may cause schedule or price issues for the
2 Units.”

- 3 • Construction Efficiencies: “The project schedule and costs are
4 based on efficiencies and economies anticipated from the use of
5 [standardized designed and advanced modular construction
6 processes]. . . . However, standardized design and advanced
7 modular construction has not been used to build a nuclear facility
8 in the United States to date. The construction process and
9 schedule is subject to the risk that the benefits from standardized
10 design and advanced modular construction may not prove as
11 great as anticipated.”

- 12 • Rework: “[N]o AP1000 units have yet been built. Accordingly,
13 problems may arise during construction that are not anticipated at
14 this time. These problems may require repairs and rework to be
15 corrected. Repairs and rework pose schedule and cost risks
16 resulting both from the repairs and the rework itself, and from the
17 time and expense required to diagnose the cause of the problem,
18 and to plan, review and approve the work plan before
19 implementation.”

- 20 • Scope Changes: “[S]cope increases can result from changes in
21 regulation, design changes, changes in the design and
22 characteristics of components of equipment, and other similar

1 factors. . . . Scope changes represent an important category of
2 risk to which the project is susceptible.”

- 3 • Design Finalization: “[T]here is engineering work related to the
4 Units that will not be completed until after the COL [Combined
5 Operating License] is issued. Any engineering or design changes
6 that arise out of that work . . . could impact cost schedules or
7 construction schedules for the Units.”

8 See Combined Application, Docket No. 2008-196-E, Exhibit J, p. 6-12.

9 In light of these risks, SCE&G expressly acknowledged in 2008 that
10 cost and schedule updates might be required. The Commission agreed that
11 under the BLRA these updates would be allowed so long as they were not
12 due to the imprudence of the utility.

13 **Q. WHAT DO THE OUTSTANDING COMMISSION ORDERS SAY**
14 **ABOUT THE EPC CONTRACT?**

15 A. In Order No. 2009-104(A), the Commission ruled that “[a] key
16 component of the prudency review envisioned by the Base Load Review
17 Act is a review of the reasonableness and prudence of the contract under
18 which the new units will be built.” Order No. 2009-104(A) at p. 70. The
19 Commission pointed out that in the 2008 proceedings “[a] number of
20 intervenors have raised questions concerning the degree of price certainty
21 provided by the EPC Contract.” *Id.* at p. 73. However, the Commission
22 noted that this issue has been addressed in the testimony of the Company’s

1 witnesses who “testified that in the EPC Contract the Company sought to
2 obtain the greatest degree of price assurance possible, with due
3 consideration to the cost that [WEC/CB&I] would charge for accepting
4 additional price risk.” *Id.* The Commission concluded that “the EPC
5 Contract contains reasonable and prudent pricing provisions, as well as
6 reasonable assurances of price certainty for a project of this scope.” *Id.* at
7 74.

8 Mr. Byrne and I were involved in the negotiation of the EPC
9 contract, which took over two years after WEC/CB&I was selected as the
10 preferred vendor. During those negotiations, we gave serious consideration
11 to obtaining fixed or firm pricing for Craft Labor, Non-Labor Costs and
12 some or all of the potential scopes of work falling in the Time & Materials
13 (“T&M”) categories. The EAC cost adjustments presented for review in
14 this proceeding, apart from change orders, are all found in these categories.

15 As indicated in Order No.2009-104(A), we determined that the price
16 SCE&G and SCE&G customers would have paid for price certainty for
17 these items was prohibitive. In 2008, we did negotiate fixed or firm pricing
18 for more than 50% of the EPC Contract. Since that time, we have extended
19 price assurance to approximately two-thirds of the contract through
20 subsequent negotiations with WEC/CB&I. Our conclusion in 2008 was that
21 the premium to fix the prices for the remaining EPC cost categories was too

1 high. The Commission expressly approved that decision as reasonable and
2 prudent in Order No. 2009-104(A).

3 In spite of the increased costs we are considering today, the decision
4 to forego price certainty in 2008 was the correct decision. I have
5 participated in the EPC Contract negotiations and can affirm that the cost
6 increases we are facing today do not exceed the cost that would have been
7 paid for additional fixed price assurances under the EPC Contract.

8 **Q. SHOULD THE COMPANY POSTPONE UPDATES TO THE**
9 **SCHEDULES UNTIL ISSUES RELATED TO SCHEDULE AND**
10 **COST DISPUTES WITH THE CONTRACTORS ARE RESOLVED?**

11 A. No. It would not be prudent for the Company to defer updating its
12 cost and construction schedules until a later time:

13 1. We do not know when a more appropriate time would be. While we
14 would hope that our disputes with the contractors can be resolved by
15 negotiations, there is no timetable for those negotiations. If litigation
16 is required, the court proceedings in a matter this complex could last
17 five years or more. The final resolution might come well after the
18 project was completed.

19 2. The most important years for financing the Units will be 2015-2017.
20 Delaying a decision on these costs will inject significant uncertainty
21 in the financing plan at the exact wrong time.

1 3. If SCE&G foregoes adjusting its cost and construction schedules, it
2 foregoes including these costs in revised rates filings. Without
3 revised rates, SCE&G loses revenue that is required to support the
4 debt the Company plans to issue in the coming years and to support
5 common stock. Our financial plan for completing these Units is
6 based on regular, annual revised rates filings. Without the revenue
7 from revised rates, our debt service ratios, and other financial ratios
8 begin to erode immediately resulting in a financial plan that rapidly
9 becomes unworkable.

10 4. The financial community expects us to update our schedules and
11 proceed with revised rates as we have every year since 2009. If we
12 are not able to proceed consistently with past practice and current
13 expectations, the financial community will swiftly reassess its
14 support for this project and the confidence it has in the Company's
15 financial plan. This is the most important point of all. The
16 consequences of the Company not proceeding with updates and
17 revised rates filings as the BLRA envisions could result in an
18 immediate withdrawal of financial support for this project.

19 5. Not to proceed with this filing would also be contrary to our long-
20 standing commitment to this Commission and the public to come
21 forward publically for approval of changes in our cost and
22 construction schedules as we identify them.

1 Without approval of the cost and construction schedules proposed here, the
2 Company's ability to finance the completion of the Units on reasonable
3 financial terms may be placed in great jeopardy.

4 **Q. IF THESE DISPUTES ARE UNRESOLVED, HOW CAN COST AND**
5 **CONSTRUCTION SCHEDULE UPDATES BE APPROVED?**

6 A. The cost and construction schedules presented for approval here are
7 no different from those approved in 2008 and in each update docket
8 thereafter. In each case, the Company came before the Commission with
9 the best information available concerning the anticipated construction
10 schedule for completing the Units and the anticipated costs associated with
11 that schedule. In every case, both the cost and the construction schedules
12 presented and approved have been anticipated schedules for completing the
13 Units. As anticipated schedules they are subject to risks, uncertainties,
14 potential changes and possible revisions. That is true of the cost schedule
15 here just as it has been true of all cost schedules the Commission has
16 approved to date.

17 The current schedules reflect the best information available about the
18 anticipated costs and construction timetables for completing the project.
19 The anticipated capital costs presented here are not speculative. As Mr.
20 Byrne testifies, they are based on a careful review of construction plans and
21 the costs of the tasks required to complete them. No speculative or un-
22 itemized costs are included in this cost schedule. There is no question that

1 these costs on this schedule will be paid. The only question is whether
2 SCE&G can recover some of these costs from WEC/CB&I. It is appropriate
3 that this cost schedule be approved under the BLRA as the updated
4 schedule for the project.

5 **Q. SHOULD WE WAIT FOR CHANGE ORDERS?**

6 A. No. A change order is not needed to properly consider these updates.
7 The Construction Labor, and Non-Labor Costs, which constitute the Target
8 Cost categories under the EPC Contract, are not fixed or firm. T&M costs
9 are also not fixed or firm. Change orders to the EPC Contract are not
10 required for WEC/CB&I to bill SCE&G for amounts above the target or
11 estimated levels.

12 **Q. HOW WILL REGULATORS ENSURE THAT IMPROPER**
13 **CHARGES ARE NOT INCLUDED IN REVISED RATES?**

14 A. As is always the case under the BLRA, revised rates are based on
15 actual payments only, not projections. They never reflect costs that have
16 not been paid. In all cases when SCE&G files for revised rates, the
17 Company presents ORS with the actual invoices and other cost data
18 establishing the project costs that have been paid to date and information
19 justifying those costs. ORS has full audit authority over this data. ORS
20 carefully audits all amounts SCE&G seeks to include in revised rates
21 recovery.

1 SCE&G has no interest in including any improper amounts in
2 revised rates recovery. If anything improper is found in these amounts
3 through ORS's audits or otherwise, we will thank the party that points that
4 out and remove those amounts from revised rates filings immediately. If
5 those amounts were improperly invoiced to us by WEC/CB&I, we will take
6 appropriate action with WEC/CB&I to have their invoices corrected and
7 proper credits applied.

8 **Q. HAS SCE&G APPROVED THESE UPDATED SCHEDULES?**

9 A. SCE&G has "approved" the updated schedules in the sense that it
10 recognizes them to be the most accurate and dependable statements
11 available of the anticipated construction schedule for completing the Units
12 and the anticipated schedule of capital costs for completing the Units. As a
13 practical matter, these schedules are in fact the schedules under which work
14 on the project is proceeding. Insofar as they reflect data from WEC/CB&I,
15 that data has been endorsed by WEC/CB&I as contractor under the EPC
16 Contract. SCE&G has carefully reviewed the data provided by WEC/CB&I
17 and verified its reasonableness. SCE&G has also provided certain data of
18 its own that is included in the cost schedule, specifically data as to Owner's
19 cost and payments it intends to withhold from WEC/CB&I. SCE&G stands
20 behind its data completely.

21 For these reasons, SCE&G has determined that the anticipated cost
22 schedule presented by Ms. Walker (Exhibit No. ____ (CLW-1)) and the

1 anticipated construction schedule presented by Mr. Byrne (Exhibit No. __
2 (SAB-2)) are reasonable and prudent basis on which the Commission may
3 update the approved BLRA schedules for this project. The schedules
4 presented here in every way meet the definition of the anticipated
5 construction schedule and the anticipated capital cost schedule for the
6 project. They are appropriate schedules for the Company to bring forward
7 to the Commission for review and approval under BLRA. In that regard
8 SCE&G has approved these schedules for filing as updated project
9 schedules as the BLRA purposes.

10 However, for purposes of the EPC Contract, we are concerned that
11 WEC/CB&I may seek to take the term “approved” as applied to these
12 schedules to mean that SCE&G has approved substituting these schedules
13 for the schedules previously approved in the EPC Contract, thereby
14 excusing WEC/CB&I from contractual obligations, penalties, claims and
15 possible damages from failing to meet those schedules. SCE&G has not
16 approved those schedules in that sense whatsoever. In its role as Owner of
17 the project, SCE&G intends to maintain all claims and exert all possible
18 leverage over WEC/CB&I related to its obligations under the EPC
19 Contract.

20 **Q. WHAT IS YOUR CONCLUSION AS TO THE VALUE THAT NEW**
21 **NUCLEAR GENERATION BRINGS TO YOUR CUSTOMERS AND**
22 **TO THE STATE OF SOUTH CAROLINA?**

1 A. SCE&G continues to pursue the generation plan that it presented to
2 this Commission in 2008. That strategy remains fundamentally sound.
3 When SCE&G came before the Commission in 2008, we presented a
4 detailed overview of the risks and challenges of building a nuclear plant.
5 We showed then that the benefits to our customers from new nuclear
6 capacity far outweighed these risks and challenges.

7 We are now seven years into a twelve year construction project. As
8 Mr. Byrne testifies, the project team has overcome many of the one-of-a-
9 kind challenges presented by this project. The financial information I have
10 provided shows that the impact of lower inflation, lower debt costs and
11 increased production tax credits will offset the impact of capital cost
12 increases. Because of these off-sets, the costs of the project to customers is
13 no greater today that it was in 2008 when SCE&G first came to the
14 Commission for its approval.

15 Furthermore, the environmental imperatives of reducing CO₂
16 emissions are greater than ever. The risks of building a system with an
17 imbalanced reliance on fossil fuels for dispatchable base load capacity is
18 certainly no less than it was in 2008.

19 As Dr. Lynch testifies, the Company has updated its modeling of the
20 cost of completing the Units compared to other alternatives. That modeling
21 demonstrates that even with today's low natural gas prices—which I believe
22 are not sustainable over the long run—completing the Units remains the

1 lowest cost alternative for meeting the pressing need of SCE&G's
2 customers for base load generating capacity. The financial benefits of
3 completing the Units are clear even when the risk of future natural gas
4 volatility is ignored.

5 In light of these facts, we believe that the logical and prudent choice
6 is to proceed with the construction plan and apply the BLRA as written.
7 The BLRA is the basis on which the project has been successfully financed
8 to date. It will be the basis for all future financings. The BLRA is the basis
9 on which SCE&G maintains the creditworthiness necessary to continue this
10 project. Deviating from the consistent application of the BLRA would put
11 the financial plan for completing the Units at grave risk. That could
12 increase the costs of the project to customers dramatically and could well
13 result in the financial community denying SCE&G access to capital on
14 reasonable terms. That could make completing the Units financially
15 impossible which would be a great loss to our customers, to our partner
16 Santee Cooper, and to our state.

17 My senior management team and I are directly involved in the
18 management and oversight of the project and in interacting with
19 WEC/CB&I and its senior leadership team. We are dealing with the issues
20 with WEC/CB&I aggressively and at the highest levels. The challenges we
21 are facing are consistent with the risk we identified in our filings in 2008.

1 The important point is that these challenges do not in any way outweigh the
2 long-term benefits of adding this new nuclear capacity to our system.

3 The construction phase we are in today is temporary. If we stay the
4 course with construction and with regulation, the Units will be built and
5 will provide reliable, non-emitting base load power to our customers for 60
6 years or more. It is my opinion based on thirty-eight years' experience in
7 this industry that the value of the new nuclear capacity under construction
8 today remains much greater than any challenges we have encountered or
9 are likely to encounter during construction of the project.

10 **Q. WHAT ARE YOU ASKING THE COMMISSION TO DO?**

11 A. SCE&G is asking the Commission to approve the updated cost
12 forecast and construction schedule for the Units as presented in the Petition
13 in this matter and in the testimony of Mr. Byrne, Mr. Jones, and Ms.
14 Walker. SCE&G requests that the Commission find that the changes in
15 cost and construction schedules are the result of risks that have long been
16 identified as pertaining to a project of this size and complexity. Moreover,
17 SCE&G requests the Commission to find that SCE&G's management and
18 development of the project continues to be reasonable and prudent in all
19 respects.

20 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

21 A. Yes. It does.